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Assessing the integrity of fault- and top seals at CO_2 storage sites

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Abstract

Induced stress changes due to CO_2 injection into geological reservoirs can mechanically damage bounding fault- and top seals creating preferential pathways for CO_2 migration from the containment or trigger existing faults causing seismic activity at storage sites. In this paper we present geomechanical simulations of the poro-mechanical effects, thermal and chemical effects of CO_2 injection on the integrity of fault- and top seals. Simulation work was performed as part of recent feasibility studies for geological CO_2 storage in a depleted gas field and a saline aquifer in the Netherlands. Poro-mechanical and thermal effects were investigated using site-specific finite element and finite difference models as well as (semi-)analytical methods. Long term chemical effects were investigated using generic discrete element models of a representative anhydrite caprock sample. The analysis show that (1) geomechanical numerical models can be used to define clear criteria for maximum admissible pressure build-up during CO_2 injection to prevent caprock fracturing, shearing of pre-existing fractures and fault reactivation, (2) combined poro-elastic and thermal effects of CO_2 injection may induce fracturing in the near-well area, (3) long term chemical reactions of anhydrite caprock with CO_2-rich fluids may cause significant reduction in failure strength at timescales of ~50000 years.

Keywords: CO_2 storage; seal integrity; fault integrity; fault reactivation; reservoir geomechanics.

1. Introduction

CO_2 injection into depleted hydrocarbon reservoirs or deep saline aquifers will change the stress-strain field in a reservoir-seal system due to various phenomena: poro-mechanical effects caused by changes in the pore fluid pressure; buoyancy effects caused by changes in the pore fluid density; thermal effects caused by changes in the pore fluid temperature; and chemical effects caused by changes in the pore fluid chemistry. As a result, the integrity of fault- and top seals may deteriorate leading to fault reactivation and CO_2 migration through pre-existing sealed faults or newly created fracture systems in the top seals.

In recent years various research institutions, universities and companies conducted geomechanical evaluations of several currently active storage sites in Europe, e.g. Sleipner aquifer located offshore Norway (ongoing CO_2 injection since 1996, [1]); the Snøhvit field located offshore Norway; the K12-B gas field located offshore Netherlands [2] and depleted hydrocarbon reservoirs in the Paris basin [3]. Several other potential sites were also

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geomechanically evaluated such as the De Lier field located onshore Netherlands nearby the city of Rotterdam [4], the Barendrecht field located also nearby Rotterdam, and a number of other potential sites (depleted gas fields and aquifers) whose locations is not publically disclosed. In many cases the results of these site-specific geomechanical evaluations are only available as unpublished and often confidential reports.

In this paper we present geomechanical simulations of the poro-mechanical, thermal and chemical effects of CO_2 injection on the integrity of fault- and top seals. Simulation work was performed as part of recent feasibility studies for geological CO_2 storage in a depleted gas field and a saline aquifer in the Netherlands.

2. Poro-mechanical effects on the integrity of fault- and top seals

Poro-mechanical effects are caused by pressure build-up due to CO_2 injection in a depleted hydrocarbon field or a deep saline aquifer. Pressure changes induce changes in the stress field, which, in turn, cause the mechanical impact on fault- and top seals. These seals must not be mechanically damaged, or fractured, during CO_2 injection and storage operations. Besides the mechanical impact on seals and faults that may lead to migration of CO_2 out of the containment, injection may induce ground movement, which can be either aseismic, in the form of surface deformation (uplift), or seismic, in the form of micro-seismic and seismic events.

We performed multiphase fluid flow and geomechanical simulations to investigate poro-mechanical effects on fault- and top seals for geological CO_2 storage in a depleted gas field [4,5] and a deep saline aquifer in the Netherlands. Here we present the key results and our observations based on these results.

2.1. Injection in a depleted gas field

The stress changes were calculated on a 2D plane strain finite element model (developed with a finite element code DIANA, [6]) which depicts the geological structure of the field under study. Pore pressures from reservoir simulation were used as input loads to geomechanical simulation. The effects of both reservoir depletion and subsequent CO_2 injection were simulated as both induce stress changes in the field.

The results of finite element analysis provide detailed insight into stress evolution in the reservoir-seal system. The analysis helps identifying zones undergoing compaction or stretching that may be at risk of mechanical failure. When the reservoir rock undergoes a full cycle of elastic compaction during depletion and expansion during injection, the reservoir stress paths for injection will be fully reversed with regard to the stress path caused by depletion. Magnitude and sense of stress changes will be, however, different for the reservoir rock and top seals assuming both deform elastically (Figure 1). The effective stress change in the top seal, resulting from pore pressure change in the reservoir, is relatively small compared to the change in the effective stress in the reservoir. The difference between top seal and reservoir is typically one- to two orders of magnitude. The small stress change in the top seal will generally not lead to the mechanical failure of the seal providing that the pressure in the repressurized reservoir does not exceed the initial reservoir pressure. This conclusion is valid assuming that the top seal was not mechanically damaged during production period, i.e. it still has sealing properties of a proven effective seal that has retained hydrocarbon column over millions of years.

Analysis of stress evolution on the reservoir-bounding faults can be utilized to determine whether CO_2 injection has stabilizing or destabilizing effects on faults. For example, in the case of an irreversible reservoir stress path during reservoir repressurization, the stress path will only partly recover and therefore converge faster towards the Mohr-Coulomb failure envelope (Figure 2). This type of stress development is less favorable as the conditions for fault reactivation will be reached earlier than in the case of a reversible stress path and the pure elastic response of the reservoir. In the feasibility study it was recommended that the reservoir stress path during repressurization was monitored by conducting repeated minifrac and extended leak-off tests in order to decrease the uncertainty in the estimate of the potential for fault reactivation during CO_2 injection.

2.2. Injection in a deep saline aquifer

The poro-mechanical effects causing induced stress changes and associated surface deformation due to CO_2 injection in a saline aquifer in the Netherlands were estimated using analytical and semi-analytical approaches. Pore pressures from multiphase fluid flow simulation were used as input for geomechanical analysis. Input data for geomechanical models were obtained from detailed geological interpretation and geomechanical characterization of the study area, regional pressure and in situ stress data.

The analyses conducted enabled us to make some general observations on the poro-mechanical effects of CO_2 injection in aquifers related to pressure build-up, which are given below:

- Pressure build-up in excess of the initial hydrostatic pressure will cause loading that was probably not experienced by the seals in the geological past.
- Pressure build-up will propagate throughout the aquifer usually far away from the injection site and CO_2 accumulation (Figure 3).
- Sealing properties of the top seal are usually not that well known, or can not be that well constrained, as in the case of hydrocarbon-proven seals overlying depleted reservoirs.
- Input data for geomechanical evaluation are even sparser than in the case of depleted hydrocarbon reservoirs.

The storage capacity of CO_2 in a saline aquifer can be considerably limited because of constraints on pressure build-up. Geomechanical constraints can be defined with respect to the maximal admissible injection and reservoir pressures which must not be exceeded during CO_2 injection. Two different sets of constraints can be put forward:

- The first constraint is related to the sealing capacity of the top seal. The admissible overpressure is in this case determined by the capillary entry pressure to supercritical and gaseous CO_2.
- The second set of constraints is related to the mechanical integrity of bounding seals and comprises (Figure 4):
    - Risk of fracturing of the reservoir rock and subsequent fracture propagation in the top and fault seals. The admissible overpressure is here determined by the magnitude of the minimum horizontal in situ stress.
    - Risk of shearing of pre-existing fractures. The allowable overpressure is determined by the mobilized shear capacity, i.e. the shear strength-to-stress ratio, of fractures.
    - Risk of fault reactivation. The allowable overpressure is determined by the mobilized shear capacity of existing faults.

In the feasibility study of CO_2 storage in a deep saline aquifer in the Netherlands we used analytical methods to estimate stress evolution in the reservoir during CO_2 injection. This approach permits rapid analysis of the poro-elastic effects of pressure build-up that have the largest effects on the reservoir rock and reservoir-bounding faults. Analyses indicate that increasing the reservoir pressure will first cause shearing along pre-existing fractures, followed by the shear and/or tensile failure of the intact reservoir rock (Figure 4).

The potential for fault reactivation during CO_2 injection was also assessed using the slip-tendency analysis [7]. In this approach the tendency of a fault surface to undergo slip in a given stress field can be assessed depending on its orientation and frictional properties. The stress state of fault segments is expressed as a reactivation potential or slip tendency, which quantifies the proximity of fault segments to the Mohr-Coulomb failure criterion. If the slip tendency value of a fault segment is higher than the coefficient of frictional sliding defining the Mohr-Coulomb failure criterion (assuming cohesion is negligible), the segment is critically stressed and likely to slip and leak. The pressure increase predicted by reservoir simulations (Figure 3) does not lead to critically stressed fault segments. It was therefore concluded that chosen injection rates and volumes will unlikely be sufficient to cause fault reactivation and leakage across fault seals.

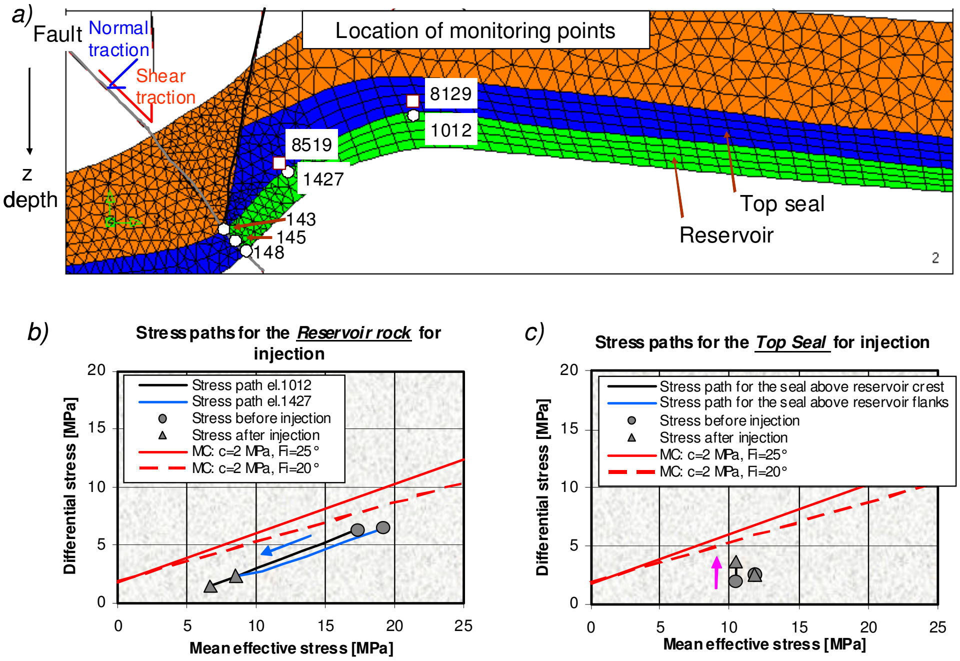

Figure 1 Stress changes in the reservoir rock and top seal resulting from CO_2 injection in a depleted hydrocarbon field. The reservoir average pressure increase amounts to 12 MPa.
a) Part of the finite element model of the storage site showing locations of the elements used to present the results of geomechanical analyses.
b) Stress changes in the reservoir rock shown by stress path diagrams. The stress paths not converging towards the Mohr-Coulomb (MC) failure envelope indicate a non-critical stress development with respect to shear failure.
c) Stress changes in top seals are much smaller than in the reservoir - in many cases by two or more orders of magnitude. However, the stress development due to injection is critical as the state of stress moves towards the failure envelope.

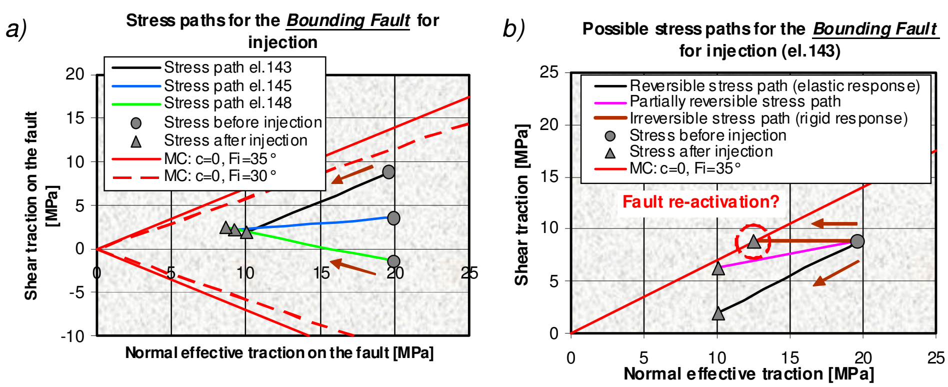

Figure 2 Stress changes on the reservoir-bounding fault resulting from CO_2 injection in a depleted hydrocarbon field.
a) Stress changes at different locations on the fault (locations of elements 143, 145 and 148 are shown in Figure 1a). Stress paths for injection are assumed to be fully reversible (i.e. overlapping) with respect to stress paths for depletion.
b) Possible stress paths for element 143 on the fault. Rigid response of the reservoir results in an irreversible critical (horizontal) stress path that may lead to slip on a fault and induced (micro-) seismicity at the storage site.

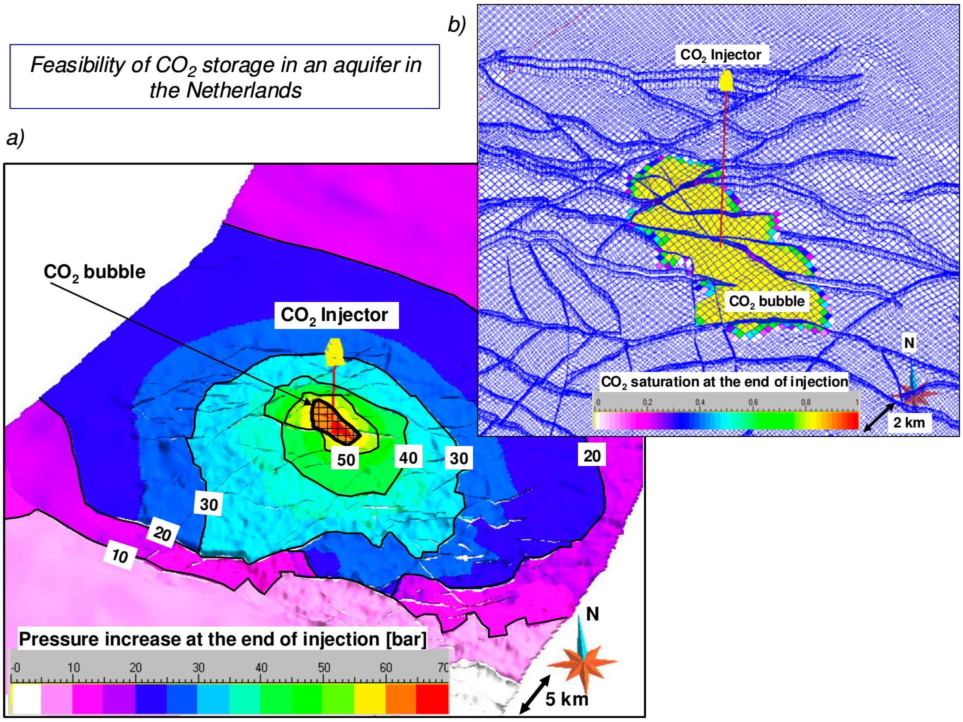

Figure 3 Reservoir simulation results of CO_2 injection into a deep saline aquifer.
a) Footprint area of elevated pressure in an aquifer extends over a large area (~100's km^2) beyond the CO_2 plume.
b) Footprint area of the CO_2 plume (~ 20 to 30 km^2).

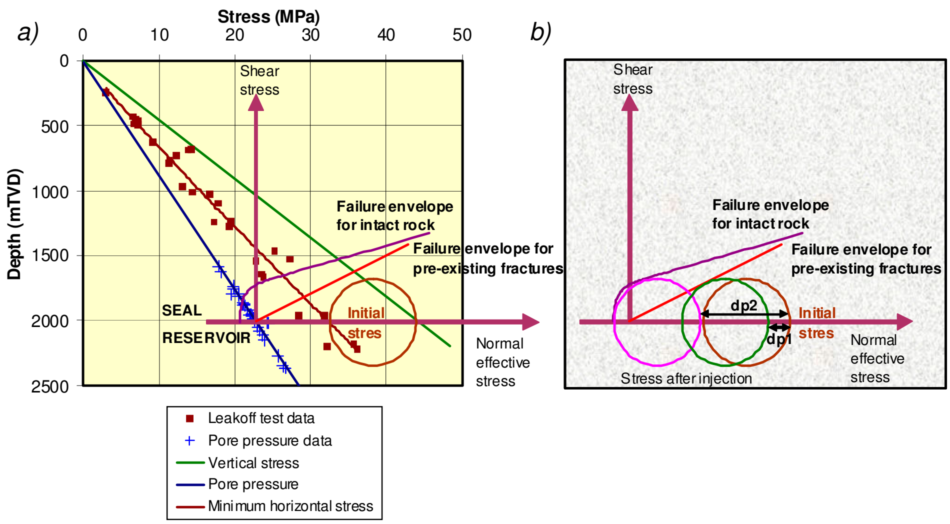

Figure 4 Stress and pressure changes due to CO_2 injection in a deep saline aquifer.
a) Initial stress before CO_2 injection. Note that the graph of shear stress versus normal stress is plotted on top of the graph showing vertical stress, minimum horizontal stress and pore pressure versus depth.
b) Analytical estimate of stress evolution in the reservoir resulting from CO_2 injection. Increasing the pressure (dp1) causes shearing of pre-existing fractures and faults. Further pressure increase (dp2) leads to shear failure and/or tensile failure, i.e. fracturing of the intact reservoir rock.

3. Thermal effects on the integrity of fault- and top seals

Coupled thermo-poro-mechanical effects are expected to occur when cold CO_2 is injected into a hot reservoir. Poro-mechanical effects lead to a decrease in effective compressive stresses in the reservoir. Thermal effects due to cooling of the rock lead to additional lowering of the horizontal stresses and thermal contraction of the rock in the near-well area affected by temperature change. As both poro- and thermal effects cause stress reduction, pre-existing fractures and faults can be earlier reactivated in shear, or the rock can be fractured under lower injection pressures, than in the case of isothermal injection.

We performed thermal multiphase fluid flow simulations to investigate thermal effects of CO_2 injection in a depleted gas field. The target sandstone reservoir is at a depth of 1300m. The difference in temperature between the injected CO_2 and the reservoir rock at the bottom of the injection well is 20°C. The simulation results indicate that the overall temperature effects are limited to the near-well area. During injection, temperatures in the rock adjacent to the injection well gradually drop from the initial reservoir temperatures to that of the injected fluid, while the low-temperature zone gradually enlarges as long as the injection is maintained. The radius of the affected area after 7 years of injection is limited to less than 150m, with steep temperature gradients around the well. The largest temperature drops are expected after shut-in of the well, due to an instantaneous drop in the bottom hole pressure. Expansion of CO_2 in the near-well area causes a decrease of the temperature due to the Joule-Thompson, which affects only a small area around the injection well.

Injection-induced thermal stress $\Delta\sigma_T$ (MPa), caused by a temperature difference ΔT (°C) between the injected CO_2 and the rock, depends on the Young's modulus E (MPa), Poisson's ratio ν (-) and the linear thermal expansion coefficient α (°C^{-1}) of the rock. Induced thermal stress was calculated with the geomechanical simulator FLAC [8], using as input temperatures from reservoir simulations, and using the following analytical expression [7]:

$$\Delta\sigma_T=\alpha E\Delta T/(1-\nu) \quad (1)$$

FLAC results showed that the induced thermal stresses will be limited within a 200m radius from the injection well. As a result of thermal contraction, stress redistribution occurs above the low-temperature zone. This is known as stress arching, which also occurs at larger scales above compacting reservoirs due to pore pressure reduction during hydrocarbon production.

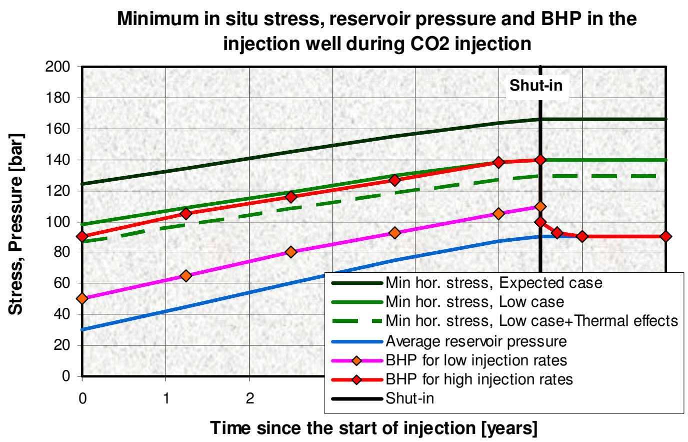

Figure 5 Evolution of the minimum in situ stress (Shmin) and reservoir pressure compared to the bottom hole pressure (BHP) in the injection well during CO_2 injection in a depleted reservoir.

In an attempt to analyze the potential for injection-induced fracturing during CO_2 injection in a depleted reservoir, we compared evolution of the minimum in situ stress in the reservoir with the bottom hole pressure in the injection well for different cases (Figure 5). The minimum in situ stress and the induced thermal stress were estimated analytically, while the bottom hole pressure was based on multiphase fluid flow simulation. A few cases can be differentiated here: (i) For the Expected case of the minimum in situ stress, the minimum stress is larger than the bottom hole pressure indicating injection without induced tensile fracturing of the reservoir rock. (ii) For the Low case, the minimum stress is near to the bottom hole pressure for high injection rates indicating possible fracturing. (iii) For the Low case with additional thermal effects in the near-well area, the minimum stress is lower than the bottom hole pressure indicating fracturing.

This study shows that injection-induced fracturing of the reservoir rock can occur in the near-well area as a consequence of poro-elastic and thermal effects of CO_2 injection. In future work, fracturing simulators can be used to investigate potential growth of injection-induced fracture in the reservoir and top seal.

4. Long term chemical effects on the integrity of fault- and top seals

The long term integrity of fault and top seals at CO_2 storage sites can be affected by chemical reactions of CO_2-rich fluids with fault or caprock. Altered rock mechanical properties in combination with changed stress conditions may result in fault reactivation and fracture initiation or propagation through caprock. The mechanical properties of fault or caprock can be significantly altered if reaction products with different volume and geomechanical properties are produced. Considering the low permeability of seals, a positive feedback between reactive flow of CO_2-rich fluids and fracture propagation is critical for this to occur. Such coupled chemical-hydromechanical processes are difficult to investigate using laboratory experiments as reaction kinetics are generally slow.

Our investigation aims to explore modeling techniques for coupled chemical-mechanical modeling suitable for assessing the feasibility of CO_2 migration out of the containment by reactivation of reservoir-bounding faults, or fracturing of caprock, as a result of long-term reactive transport of CO_2-rich fluids. As a first step, we have investigated the long term mechanical effects of chemical reactions between CO_2 and anhydrite caprock.

We used a discrete element model (PFC2D, [9]) for simulation of reactions and deformation of a typical anhydrite caprock sample in contact with CO_2-rich fluids (Figure 6). Discrete element models are particular suitable for simulating grain-scale processes, such as chemical reactions and fracture propagation (e.g., [10]). We chose to closely simulate a sample of representative anhydrite caprock from the Permian Zechstein formation in the Netherlands as used in an experimental study by Hangx et al. [11] to be able to use experimentally-derived reaction rates and compare experimental and model results. The model consists of mm-sized clusters of circular elements representing acicular rosettes (60 vol%) embedded in a matrix of 50-83 μm-sized clusters of 3 overlapping circular elements representing euhedral to subhedral anhydrite (40 vol%) (c.f. [11]). The model is kept relatively small (2.5x2.5 mm) to be able to simulate reactions between anhydrite and CO_2 at the grain scale and maintain reasonable computation times. The initial sample strength is calibrated using experiments on wet anhydrite from [11] by changing inter- and intracluster bond strengths. We simulated the following reaction of anhydrite with CO_2 and water at high CO_2 pressure occurring at a rate of ~10^{-8} mol/m^{2}s, resulting in a 20% volume decrease in the solid phases [11];

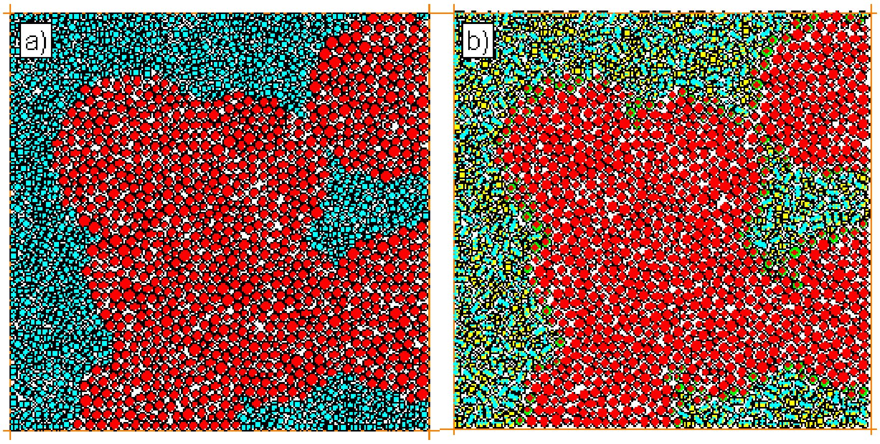

Figure 6 Discrete element model of anhydrite caprock a) before reaction with CO_2 and b) after 50,000 years exposure to CO_2-rich fluids. Matrix anhydrite grains (blue), anhydrite rosettes (red), reaction rims of calcite in matrix grains (yellow) and rosettes (green) are indicated.

$$CaSO_4 + CO_2 + H_2O \rightarrow CaCO_3 + H_2SO_4 \quad (2)$$

Changes in mechanical behavior of the sample due to the volume decrease associated with this reaction were simulated at stress and temperature conditions representative for a caprock buried at ~ 2.5 km depth (σ_v = 50 MPa,

σ_h = 40 MPa, T = 80 ºC) for 50,000 years. Simulations were performed for time intervals of 100 years, with for each time interval (1) a volume change of matrix grains and edges of rosettes according to the reaction rate of equation 1, (2) re-equilibration of applied stresses and associated volume decrease, failure of intergranular bonds and grain rearrangement at the end of each time interval, (3) determination of sample strength at different horizontal stresses by simulating biaxial tests on the sample. It is assumed that the entire sample is in contact with CO_2-rich fluids. In reality fluid penetration in the caprock is likely to be very slow due to the low permeability of the caprock, although this process may be aided by fracture propagation. The model is therefore representative of caprock at the reservoir-caprock boundary or near open fractures rather than for intact caprock.

Figure 6 shows the anhydrite-calcite alteration in the grain (edges) as a result of the reaction with CO_2-rich fluids in the model. The biaxial tests show that anhydrite failure strength is only significantly reduced for long reaction times (~25% reduction after 50,000 years). For reaction times of ~1000 years, changes in failure strength are insignificant. This observation is in agreement with conclusions of Hangx et al. [11]. It means that reaction of CO_2-rich fluids with caprock is only likely to significantly changes caprock permeability at timescales of ~50,000 years.

This study shows that coupled chemical-mechanical modeling of the effect of reactive flow on caprock deformation using discrete element models is feasible. In future work, this modeling technique can be used to more rigorously test potential migration scenarios related to coupling between reactive flow and deformation using local stresses from the finite element models described above. In addition the models can be used to simulate changes in capillary entry pressure for CO_2-rich fluids.

5. Concluding remarks

We presented geomechanical simulations of the poro-mechanical, thermal and chemical effects of CO_2 injection carried out in recently accomplished feasibility studies of geological CO_2 storage in a depleted gas field and a saline aquifer in the Netherlands. Geomechanical numerical models provided detailed insights into stress evolution and associated deformation in the reservoir-seal system and faults as well as the long term effects of CO2 storage on top seal integrity. Conducted analyses enabled us to put forward geomechanical and hydraulical criteria for the maximum admissible pressure build-up during CO_2 injection. These criteria are related to the risk of induced fracturing of the reservoir rock and the caprock, the risk of shearing of pre-existing fractures and the risk of fault reactivation leading to injection-induced seismicity. Detailed geological/geomechanical characterization of the potential storage site and field monitoring during injection operations are required to constrain geomechanical models and decrease the uncertainty in their predictions.

Acknowledgements

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